Slow Coherency Based Controlled Islanding – A Demonstration of the Approach on the August 14, 2003 Blackout Scenario

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***Abstract*—This paper demonstrates the use of a slow coherency based generator grouping algorithm and a graph theoretic approach to form controlled islands as a last resort to prevent cascading outages following large disturbances. The proposed technique is applied to a 30,000-bus, 5000-generator, 2004 summer peak load, Eastern Interconnection data and demonstrated on the August 14, 2003 blackout scenario. Adaptive rate of frequency decline based load shedding schemes are used in the load rich islands to control frequency. The simulation results presented show the advantage of the proposed method in containing the impact of the disturbance within the islands formed and in preventing the impact of the disturbance from propagating to the rest of the system. This is demonstrated by the significant reduction in line flows in the rest of the system and by improved voltage and relative angle characteristics. Based on the suggestion in the joint US-Canadian task force final report on the blackout, load shedding without any islanding is also performed and results obtained are compared with the proposed controlled islanding method. The islanding method outperforms the load shedding only method in reducing the transmission line flows but both methods have similar effects on voltage and relative angle behavior.**

***Index Terms*—Slow coherency, islanding, load shedding, power system stability, blackout prevention**

I. Introduction

POWER systems are being operated closer to stability limits as a result of competition in the market and other factors that include growth in generation and demand without the concomitant transmission system expansion. Stressed system conditions together with inadequate situational awareness, ineffective vegetation management and insufficient diagnostic support can cause catastrophic failures as demonstrated by the August 14, 2003 blackout [1]. In the literature several approaches to deal with large disturbances have been proposed. Several of these tools are critical components of modern energy management systems. In general, the tools employed to defend against catastrophic failure can be categorized as either a) preventive control techniques or b) corrective control techniques.

In [2-4] a corrective control strategy that splits the system into controlled self-sustaining islands using a slow coherency approach has been presented. The islands are created based on a minimum load-generation unbalance criterion. The criterion takes into account aspects of restoration related to black start and reactive power capabilities. A load shedding scheme based on the rate of frequency decline is applied to prevent frequency instability in load rich islands. In [3], an analytical approach to automatically determine the islands from the identified slowly coherent groups of generators using an exhaustive cut set approach was developed. Reference [4] further refined the automatic island determination scheme using a max-flow min-cut, graph theoretic approach with capabilities to merge adjoining slowly coherent groups, or break coherent groups based on the location of the disturbance. Reference [9] proposes a timing schedule for controlled islanding and a possible implementation based on decision tree technology.

The proposed controlled islanding strategy was tested using the extended transient-midterm stability program (ETMSP) [5] on a 179- bus, 29-generator equivalent of the WECC system and showed potential in mitigating the impact of disturbances and preventing cascading outages. This paper presents a qualitative demonstration of the approach on the August 14, 2003 blackout scenario. The demonstration is characterized as "qualitative' because a 2004 summer peak load Eastern Interconnection base case provided by AEP was altered to represent the condition during the 2003 blackout based on the information available from the joint US-Canada task force final report [1]. As a result, the reconstruction is presumed to closely resemble actual conditions prior to the blackout. However, the reconstruction does not exactly replicate the system state that existed prior to the blackout because these details were not provided in [1] and, indeed, the full set of data may not exist.

The 2004 summer peak load Eastern Interconnection case consists of 30000-buses and nearly 5000-generators. All the modeling detail provided in the available data remains unchanged. The slow-coherency method available in EPRI's DYNRED package [6] is used to identify the generator groups. Based on the disturbance location, the minimal cut-sets are determined using a graph theoretic approach taking into account the load-generation unbalance [4]. A rate of frequency decline based load shedding scheme is then applied to the load rich islands. The results obtained clearly demonstrate that the proposed controlled islanding scheme effectively prevents the impact of the disturbance from propagating into the system and contains the impact of the disturbance within the islands thus created. In [1] it was also suggested that the cascading failure during the August 14, 2003 blackout could have been prevented by shedding load in the Cleveland area. This paper also compares the results of proposed islanding strategy with a *load shedding only* scheme in the Cleveland area. In order to make an exact comparison of the load shedding only scheme with the proposed islanding scheme the amount and locations of the loads chosen to be shed are identical. The islanding scheme outperforms the load shedding only scheme in decreasing the 345 kV transmission line flows. Comparable voltage and frequency improvements are obtained by both methods. The load shedding only scheme is also investigated for different levels and locations of load shedding. The load shedding scheme identified by the rate of frequency decline algorithm is found to be optimal and provides the best improvement in system performance.

This paper is organized as follows: Section II provides a brief overview of the slow coherency based generator grouping algorithm and rate of frequency decline based load shedding scheme. Section III describes the recreation of the August 14, 2003 scenario from the base case provided and the results of the demonstration of the proposed method. Section V presents discussion and conclusions.

II. SLOW COHERENCY BASED ISLANDING AND LOAD SHEDDING

In the controlled slow coherency based islanding approach, the determination of subregions of the electric power system, or *islands*, is a critical step. A slow coherency method [7] based on two-time-scale theory is utilized. A modification called tolerance based slow coherency [8] is used to deal with large systems and achieve more precise results. In the tolerance based approach to coherent generator identification, the user can specify tolerance values, the number of slow modes, and the number of eigenvalues of the linearized dynamic system equations being calculated. After having determined the groupings of generators using slow coherency and taking into account the location of a disturbance, an automatic controlled islanding algorithm is applied that takes into account certain physical constraints in forming islands. In these methods, two assumptions are made: 1) The coherent groups of generators are independent of the size of disturbance so that the linearized model could be used to determine the coherency group; 2) The coherent groups are independent of the level of detail used in modeling the generator unit so that a classical generator model can be considered [9].

One of the most important requirements for islanding is to minimize the real power unbalance within the islands to facilitate restoration. An efficient technique has been developed in [4] in which the problem has been converted into a search of the minimal cutsets (MCs) to construct the island with minimal net power flow. The power flows in the transmission lines also contain information of the distribution of the generators throughout the system. Once an island is formed, the net flow in the lines that must be interrupted is an indicator of the load – generation unbalance. It is assumed that losses can be ignored. In [4] the islanding problem is decomposed into two stages:

1. Find minimal cutsets
2. Obtain optimal minimal cutsets by various criteria.

Once the islands are formed, some of the islands will be load rich and some of the islands will be generation rich. In the load rich islands, the decline in frequency becomes a serious issue and an adaptive load shedding scheme has been developed and demonstrated in [2,3] to shed load based on a rate of frequency decline. A load shedding scheme based on the rate of frequency decline is used here to identify the magnitude of the disturbance. At the same time, conventional load shedding is modified in a two-level load shedding algorithm [3]. Normally, load frequency relays are used to implement a conventional load shedding scheme. Conventional load shedding has long time delays and lower frequency thresholds which can be used to prevent inadvertent load shedding in response to small disturbances. If the system disturbance is large and exceeds the signal threshold [3], a second layer will be activated and the load shedding scheme based on the rate of frequency decline will take effect. This layer of the load shedding will shed load quickly to prevent the cascading events in the island. In the generation rich islands depending on the choice of the islands created, generation reduction is normally implemented to prevent unacceptable frequency increases.

III. SIMULATION RESULTS

At this point, the controlled islanding approach is applied to the Eastern Interconnection 2004 summer peak load case. The test case has 30000-buses and nearly 5000-generators. All modeling detail provided in the base case was retained.

A. *Preparation of the August 14, 2003 Blackout Case*

To the degree that the publically available data allowed, the conditions prior to the August 14, 2003 blackout were recreated utilizing information available in the joint US-Canada task force report [1]. As a result, this analysis should be considered as a "qualitative" demonstration of the proposed approach and not a quantitative analysis. Since no information other than that available in [1] was used, the recreated case may not be exactly what existed prior to the disturbances on August 14, 2003. The changes made to the Eastern Interconnection 2004 summer peak load case are described in some detail. Table I shows the generation outages implemented:

From the details provided in [1] it was observed that starting from about 12:15 PM on August 14, several disturbances occurred in the system until the Dale-West Canton 138 kV line tripped at 16:05:55 PM. This was followed by the Sammis-Star trip at 16:05:57 PM which initiated the cascading outages. Hence, the proposed islanding scheme was initiated after the trip of the Dale-West Canton line. In general the proposed scheme will be initiated based on detailed off-line studies; it is not intended to be a real-time implementation. In the work presented here the insight gained from [1] is utilized to decide when to island. This aspect is one of the two important components of any islanding scheme and it is envisioned that off-line studies would provide the operating guidelines of when to initiate islanding. The phenomena prior to the loss of the Dale-West Canton line were slowly occurring and hence these changes were made in the recreation and a steady state power flow solution was obtained. These changes included the removal (outaged in the recreation) of several 345 kV and 230 kV lines and outage of one generator:

1. Columbus - Bedford 345 kV line
2. Bloomington - Denois Creek 230 kV line
3. Trip Eastlake 5 generation
4. Chamberlin – Harding 345 kV line
5. Stuart - Atlanta 345 kV line
6. Hanna - Juniper 345 kV line
7. Star – South Canton 345 kV line

TABLE I
LIST OF GENERATION OUTAGES – EASTERN INTERCONNECTION TEST STUDY

Generator	Bus No.	Rating		Reason for Outage
Davis-Besse Nuclear Unit (FE:202)	21630	934 MW	481 MVAr	Prolonged NRC-ordered outage beginning on 3/22/02
Eastlake Unit 4 (FE:202)	21688	267 MW	150 MVAr	Forced outage on 8/13/03
Monroe Unit 1 (DECO:219)	29055	780 MW	420 MVAr	Planned outage, taken out of service on 8/8/03
Cook Nuclear Unit 2 (AEP:205)	22655	1,060 MW	460 MVAr	Outage began on 8/13/03
Conesville 5 (AEP:205)	22703	400 MW	145 MVAr	Tripped at 12:05 on August 14 due to fan trip and high boiler drum pressure

The following 138 kV lines were also removed following the details given in [1]:

1. Cloverdale - Torrey
2. E. Lima – New Liberty
3. Babb – W. Akron
4. W. Akron – Pleasant Valley
5. Canton Central transformer
6. Canton Central – Cloverdale
7. E. Lima – N. Findlay
8. Chamberlain – W. Akron
9. Dale – W. Akron
10. West Akron – Aetna
11. West Akron – Granger – Stoney – Brunswick – West Medina
12. West Akron – Pleasant Valley
13. West Akron – Pine – Wadsworth

B. Preparation of the August 14, 2003 Blackout Case

The slow coherency algorithm available in DYNRED [6] is then applied to find the slowly coherent generator groups based on the power flow obtained from scenario *A* above and the given dynamic data. No simplifications were made and all modeling details provided in the data are included. From the analysis, 18 slowly coherent groups are obtained. Because of space constraints Fig. 1 [1] only shows the 7 groups in the vicinity of the primary disturbances.

It is noted from Fig. 1 that First Energy (FE) forms a slowly coherent group by itself. Fig. 2 provides a clearer view of the system in the FE area. The outer trace shows the boundary of the slowly coherent group identified in the FE area in some detail.

C. Automatic Islanding

The initiation of the cascading event started with the trip of the Sammis-Star line on a Zone 3 relay setting as detailed in [1]. This was the primary disturbance which caused the cascade the spread across the system. This information was used in the initiation of the automatic islanding algorithm in [4] which identifies the islands with the minimum load generation unbalance and also merges islands with a common minimal cutset if required. In general the criterion of when to island will be determined by conducting off-line analysis.

This algorithm identified a single island within the FE area as shown by the inner boundary in Fig. 2. The island created is around the Cleveland area. In order to form the island,16 lines are tripped. They include 6-345 kV lines, 5-138 kV lines and 5-69 kV lines. The total generation of the island is 3688.3 MW and the total load is 5950.4 MW. This island is load rich with a deficiency of 2262.1 MW. Frequency will decline within this load rich island. The adaptive load shedding scheme proposed in [2,3] is applied to facilitate frequency recovery within the island.

D. August 14, 2003 Scenario

As detailed in [1], the final cascade started after the Dale-West Canton 138 kV line sagged into a tree and tripped. Within 2 seconds, this led to the overloading of the 345 kV transmission line between Sammis-Star which then tripped on a Zone 3 setting.

In order to test the proposed approach, the controlled islanding algorithm described in Section III.C was initiated immediately after the loss of the Dale-West Canton 138 kV line. The island near the Cleveland area shown in Fig. 3 is then created. This is a load rich island and within the island the frequency decreases. The adaptive load shedding relays based on the algorithm described in [2,3] are installed within the FE area. These relays operate to shed a total load of 32% (1904.1) MW within the island. The results of the time domain simulation of the islanding scheme are shown with regard to selected system states in Figs. 3-5. The results are compared with the case where no islanding is done after the loss of the Dale-West Canton line.

The following statement was made in [1] "*The team found that 1,500 MW of load would have had to be dropped within the Cleveland-Akron area to restore voltage at the Star bus from*

90.8%(at 120% of normal and emergency ampere rating) up to 95.9%(at 101% of normal and emergency ampere rating)." Based on this suggestion a load shedding only approach is also examined. The load was shed in the Cleveland area immediately after the Dale-West Canton line had tripped. In this case after the Dale-West Canton line is tripped, no lines are removed to form the island but a specified amount of load at exactly the same locations identified by the load shedding scheme in the islanding case are dropped.

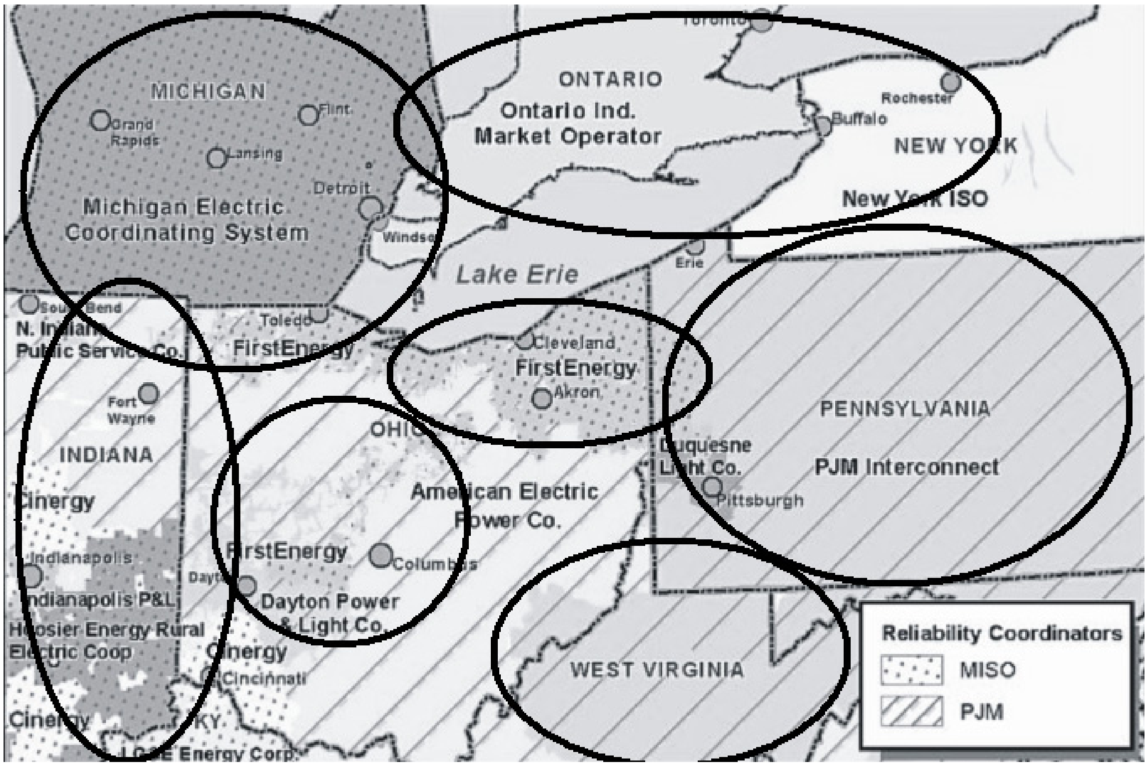


Fig. 1 Coherent generator groups identified in the Eastern Interconnection

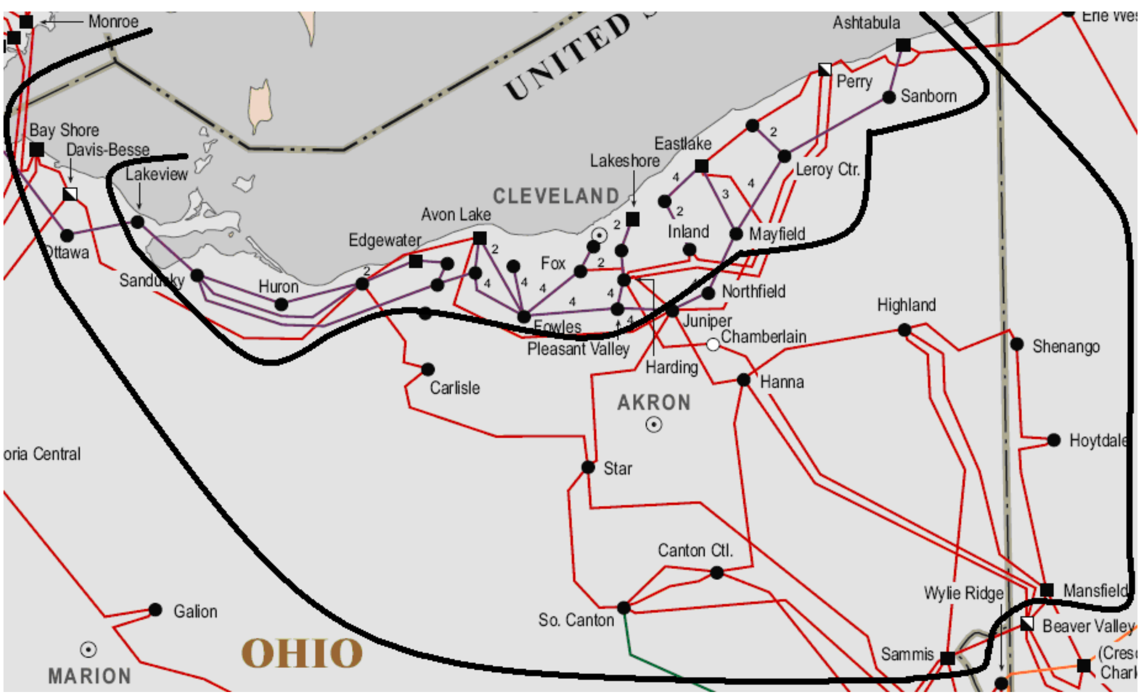
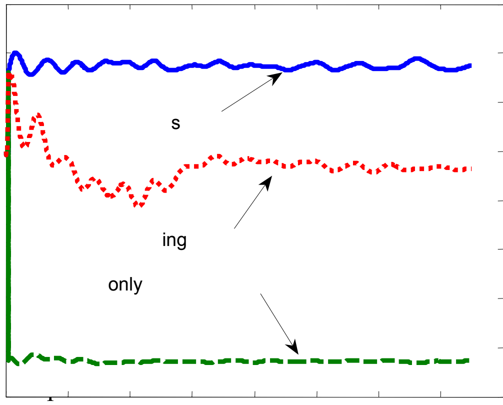


Fig. 2 FE area line connections. The outer boundary is the slowly coherent group in the FE area.
The smaller boundary close to the Cleveland area is the island created by the automatic islanding program



this case are also ly show that the the active power compared to the on the islanding Sammis buses to ad shedding only to recover to a landing. In com- en (referred to as the *fault only case*) note that the reduction in the active power flow would have significantly reduced the current flow in the Sammis-Star line. With the concomitant increase in voltage seen at either bus, the magnitude of the impedance seen by protective relays would have been considerably higher than the case in which no action was taken. Hence, the Zone 3 relay on the Sammis – Star line might not have tripped and the cascading outages might not have spread west into Ohio and Michigan.

The impact of islanding on the system is now examined. Fig. 6 shows the plot of a generator (Edgewater) within the island. Note that immediately after islanding the frequency declines. The adaptive load shedding scheme operates and drops the required amount of load as a result of which the frequency recovers in the island. The frequency values that are achieved are well within the limits (57 Hz – 62 Hz) specified in [10] which takes into account the time cumulative limits of both underfrequency and overfrequency on turbine performance. This aspect is particularly important with regard to the manufacturer defined limits at which turbines would have to be re-bladed if the cumulative limits are exceeded. A similarly conceived islanding scheme [11] is still in effect in the WECC system which breaks the system up into two islands following large disturbances,

The impact of islanding is now examined both on the rest of the system and within the island by examining a number of variables. In doing so, the performance of the case of islanding and adaptive load shedding with that of the load

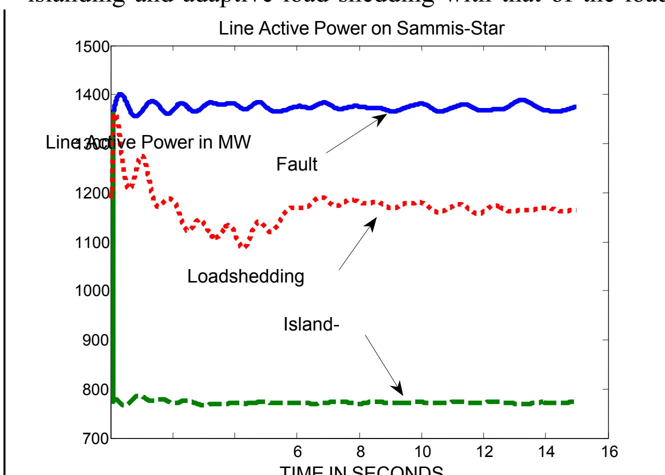


Fig. 3 Line active power flow between Sammis and Star

shedding only case is compared. .One primary premise of islanding is the ability to contain the effect of the disturbance

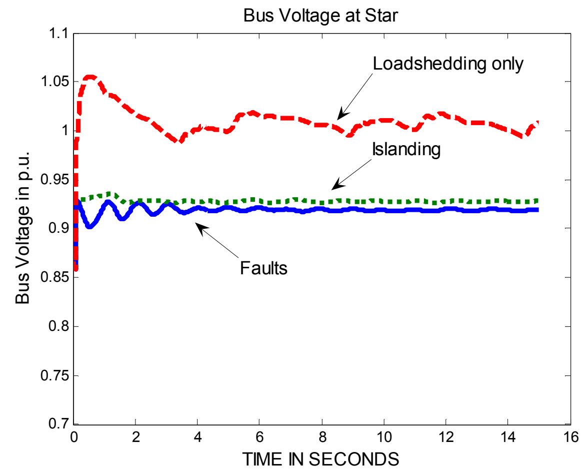


Fig. 4 Voltage in p.u. at the Star bus

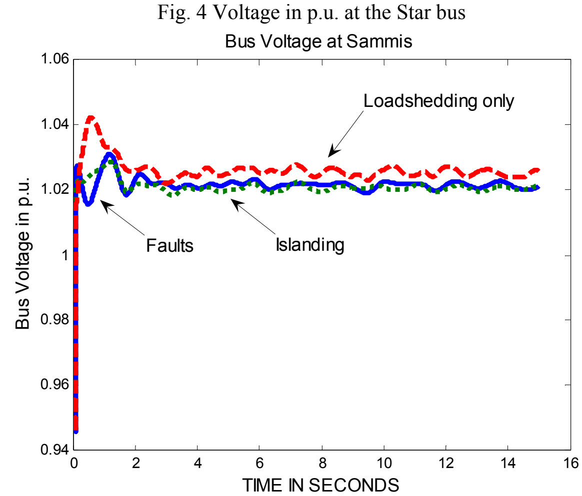


Fig. 5 Voltage in P.U. at the Sammis bus

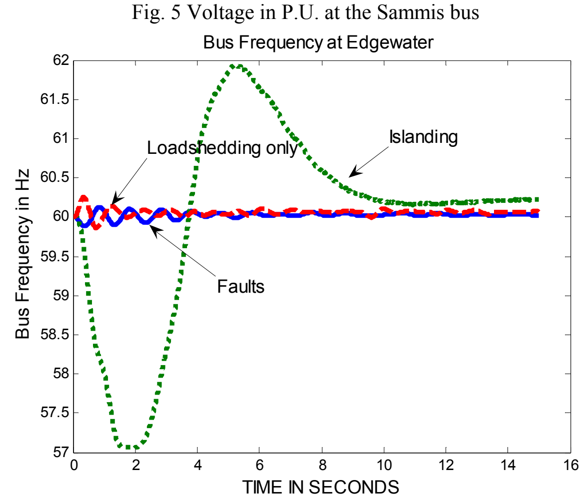


Fig. 6 Frequency at the Edgewater bus within the FE island

and to prevent the detrimental effects of the disturbance from impacting the rest of the system. In order to verify this hypothesis, the power flows on some key lines which tripped as the cascading outage progressed westward [1] are presented.

Fig. 7 shows the plot of the active power flow on the Lima – Fostoria line. Note that when controlled islanding is implemented, there is a significant reduction in active power flow on this line for several seconds after islanding is initiated. The *load shedding only case* also reduces this line flow; however, in comparison to the *faults only case*, the flow is higher than the case with islanding within 3.5s. This indicates that islanding is at least as effective in minimizing the impact of the disturbance on the western portion of the system.

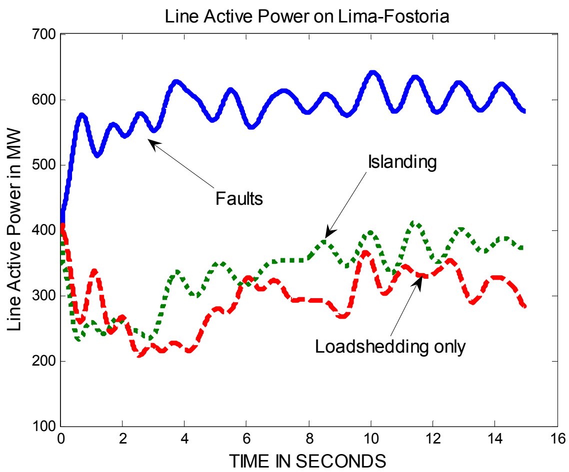


Fig. 7 Line active power flows between Lima and Fostoria

The plot of active power flow on another 345 kV line in western Ohio is shown in Fig..8: in this case too islanding reduces the active power flow in the line for more than 10 seconds after the disturbance. In the blackout recreation, controlled islanding also relieves stress eastward on the 345 kV lines carrying active power from southern Pennsylvania northward to New York state. Fig. 9 shows that the line flow on Wayne – Erie West is efficiently reduced by islanding compared to the *faults only case*. Thus the impact of the disturbance is contained in the island. However the *load shedding only* scheme does not benefit the system as much as the islanding case since the line flow is higher than in the islanding case. In Figs. 10 and 11 the frequency and relative rotor angle of two generators to the east and south of the Cleveland area are plotted to examine the impact of islanding on their behavior. It is observed that the islanding has

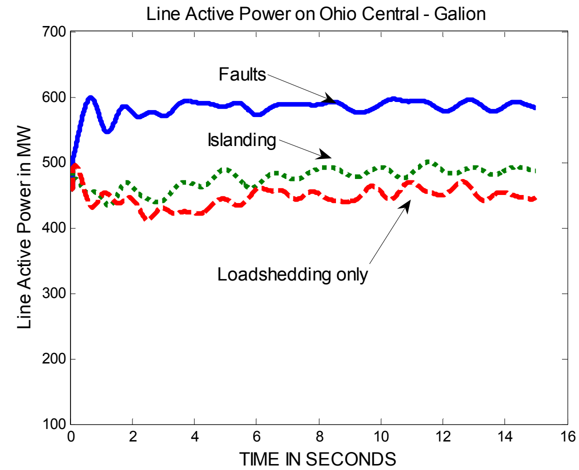


Fig. 8 Line active power flows between Ohio Central and Galion

relatively lower impact on the system to the east and south of the Cleveland area. No increase in frequency is observed in this area from which power flowed into the island.

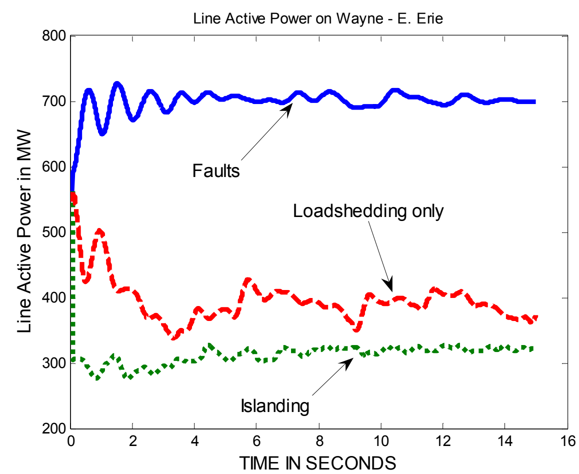


Fig. 9 Line active power flows between Wayne and West Erie

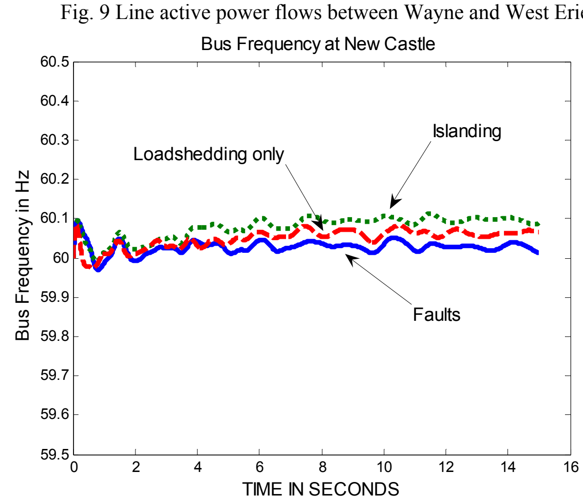


Fig. 10 Frequency at New Castle generator

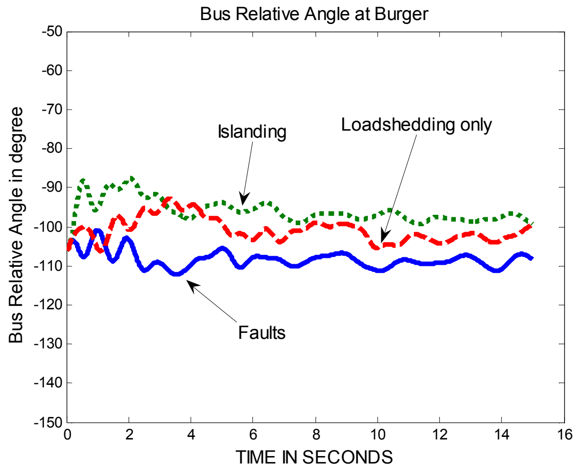


Fig. 11 Relative rotor angle at Burger

In order to examine the effect of load shedding in more detail, different load shedding schemes with different load shedding amounts and locations are examined. These cases are presented in Fig 12 where for the sake of brevity the percentage of the total load shed is indicated. It is observed that as the total load shedding amount increases, the line flow on Sammis - Star could be reduced. But when we shed load slightly higher than the proposed islanding method, the system goes unstable, as the curve labeled with 35% shown in Fig 12. Other curves showing different total percentages of load shedding only cases are also shown in Fig 12. The 32% load shedding identified by the islanding scheme provides the best performance in terms of reduction of the Sammis-Star real power flow.

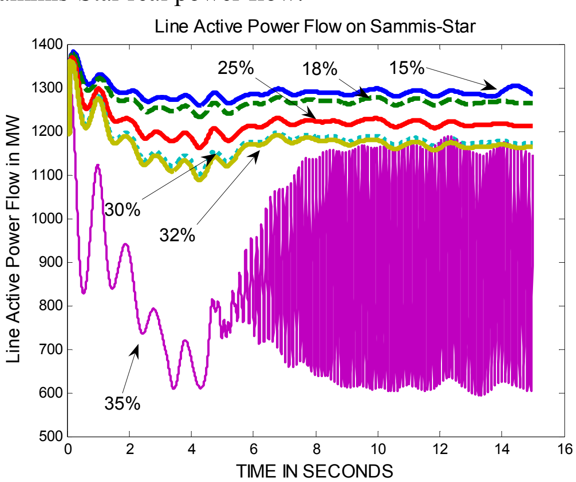


Fig. 12. Line Active Power Flow on Sammis-Star under different load shedding schemes

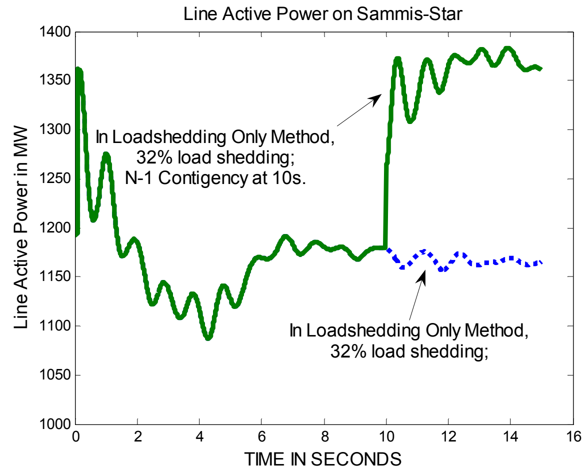


Fig. 13 Line Active Power Flow on Sammis-Star

The primary advantage of the reduced flow in the islanding case as shown in Fig. 9 is that when the system is already highly stressed, and several contingencies have occurred in the system, islanding limits the vulnerability of the system. That is, if any other contingency occurs, the case with islanding provides a less vulnerable operating condition in which the system can recover more robustly than the load shedding only case. In order to verify this assertion, the 32% load shedding only case is considered, and the Perry generator in the Cleveland area is dropped. This *N*-1 contingency results in the real power flow on the Sammis – Star line exceeding its thermal limit of 1398 MW as shown in Fig. 13. This could result in further cascades as evidenced during the August 14, 2003 blackout. In the islanding case the Perry generator is within the island formed and any disturbance inside the island is contained within the island and an appropriate amount of load could be shed to counter the impact of the lost generator. Since the system is already islanded the flow on the Sammis – Star line will not be impacted and hence not shown in the plot below.

IV. MARKET POWER AND CONTROLLED ISLANDING

The foregoing analysis of the August 2003 blackout was done in the comfort of hindsight: that is, the analysis was done totally off-line making the usual adjustments of tolerances and other engineering parameters as needed. The question as to the wisdom of whether controlled islanding can be done on-line is unresolved at this time. One issue in islanding a power system relates to the potential disruption of marketing of energy over the high voltage transmission network. It is a stated objective of power marketers to enable competitive markets as much as possible. If transmission circuits are intentionally opened, there is the potential for disabling some percentage of the power market. Note that the islanding strategy above is one of minimum disruption thus resulting in a minimum impact to power exchange. Note also that there is a cost associated with a blackout – no matter how low the probability of a large blackout may be, the cost of such an event is very high, and the product of the cost and the probability of the event is significant. It is possible to set the 'trigger points' [12] (tolerances) for initiating controlled islanding strategies conservatively so that there may be some false dismissals of major events – but no false alarms. Under such a selection of trigger points, there may be major disturbances that could develop into loss of synchronism that do not initiate the controlled islanding algorithm (i.e., a false dismissal). False dismissals could evolve into operating states that do indeed trigger the controlled islanding algorithm, or they may be handled by the conventional protective relaying that is already in place.

The controlled islanding with rate of change of frequency based load shedding has demonstrated significant potential in preventing cascading outages in a large realistic test system based on a scenario of the August 14, 2003 blackout recreated from the information available in [1]. Further work in evaluating the method and development of effective protection schemes to implement the desired controlled island may significantly enhance its effectiveness and applicability.

V. Conclusions

This paper presents a *qualitative* demonstration of a controlled islanding approach [2-4] on the Eastern Interconnection 2004 summer peak load case for the August 14, 2003 blackout scenario recreated from the information available in [1]. The results presented in the paper show that the proposed scheme would have contained the impact of the disturbance within the island that is created in the Cleveland area and would have greatly reduced the active power flow on the critical Sammis – Star 345 kV line. In addition the voltages at both the Sammis and Star buses recover significantly under controlled islanding. This observation together with the significantly reduced active power flow on the line would have reduced the line current as a result of which the apparent impedance locus would not have entered Zone 3. This in turn would have prevented the trip of the Sammis – Star 345 kV line identified [1] as the start of the cascading outages that followed resulting in the blackout of a major portion of the North American Eastern interconnection.

The controlled islanding approach is based on the determination of the slowly coherent groups of generators in the system. This step, as detailed in [3,4,7], identifies the weakest electrical links among the slowly coherent groups of generators. A graph theoretic max-flow min-cut approach together with the information regarding the location of the disturbance is used to determine the minimal cut sets among the coherent groups of generators. The minimal cut set with the smallest load generation unbalance is identified and islanding is performed. The islanding results in load rich islands or generation rich islands. In the load rich islands an adaptive load shedding scheme based on rate of change of frequency decline [2,3] is used to prevent frequency instability. In the generation rich islands, generation reduction is implemented to control the frequency. This approach works effectively in the August 14, 2003 scenario that has been recreated on the test system considered. The controlled islanding limits the impact of the series of disturbances prior to the loss of the Dale-West Canton line within the island and prevents the propagation of the detrimental effects of the disturbance to rest of the system. This is demonstrated by observing several key variables both inside and outside the island created.

The controlled islanding procedure with rate of change frequency decline based load shedding was also compared with a load shedding only scenario. The comparison showed that the load shedding only scheme would have resulted in a higher active power flow on the Sammis-Star line in comparison to the controlled islanding approach. It would have provided a slightly higher voltage at the Star bus. The controlled islanding approach however, reduces the real power line flows on the 345 kV lines both to the west and to the east of the Cleveland area and also results in significantly lower active power flows within the island. This is a particularly important because the system is so highly stressed and vulnerable to other contingencies. A contingency of a loss of a single generator is considered. This contingency demonstrates that the case with load shedding only results in the thermal rating of the Sammis-Star line being exceeded. In this regard the controlled islanding case would have made the system more robust and less vulnerable to other contingencies because of the reduced line loading.

VI. Acknowledgement

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